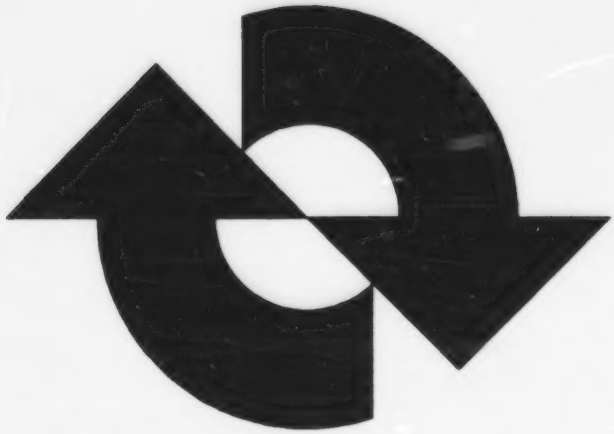

NB POWER

SULPHUR DIOXIDE EMISSION CONTROL PROGRAM 1990 - 2000

JANUARY 1990

NB POWER

SULPHUR DIOXIDE EMISSION CONTROL PROGRAM

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FORWARD

This document was originally prepared as part of the Environmental Impact Assessment documentation for the Belledune Thermal Generating Station (TGS). Following the Environmental Review process the project was approved conditionally with the requirement for the SO_2 emission rate not to exceed that set out in the federal air emission guidelines (1981). These guidelines for SO_2 emissions from new generating units are:

a. Units emitting between 0.6 $lb/10^6$ BTU and 6.0 $lb/10^6$ BTU should be controlled such that the final emission does not exceed 0.6 $lb/10^6$ BTU.

b. Units emitting more than 6.0 $lb/10^6$ BTU should be controlled so that a minimum of 90% of the uncontrolled emission is captured before release to the atmosphere.

This revised document includes the impact of the Environmental Review decision on NB Power's Sulphur Dioxide Emission Reduction Program.

I. SUMMARY

NB Power is undertaking a generation development program which is seen as being consistent with commitments to constrain SO_2 emissions to the levels required in the CANADA - NEW BRUNSWICK SULPHUR DIOXIDE REDUCTION AGREEMENT entered into in October 1987.

The program being undertaken meets the required 130,000 tonne SO_2 emission level by the year 1994 and maintains emissions at or below this level to past the year 2000. Should alternative developments to those presently proposed be undertaken the committed constraints can still be met as demonstrated in this report. The SO_2 control measures proposed are estimated to range between $300 and $400 million for capital expenditures with a total increase in annual costs of some $70 million including financing, operations, and maintenance charges.

II. BACKGROUND

The Governments of Canada and New Brunswick, in October, 1987, entered into an agreement specifying the maximum limit of annual SO_2 emissions which would be permitted within New Brunswick beginning in 1994.

This CANADA - NEW BRUNSWICK SULPHUR DIOXIDE REDUCTION AGREEMENT specified an annual limit of one hundred eighty five thousand (185,000) tonnes. The amount allotted to NB Power is one hundred and thirty thousand (130,000) tonnes. NB Power is also, of course, required to meet various land, water, and air impact constraints as stipulated by the relevant authorities.

This document relates only to the overall SO_2 emission issue and sets out the specific actions that will be taken, given the generation resource alternatives available to the utility, to ensure that SO_2 emission constraints are met.

Clearly the actions outlined in this compliance program will be modified as necessary to take account of available technology, energy sources, and fuel whenever economics and efficiency will benefit. Such modifications will not, however, compromise the ability of the utility to meet emission constraints as presently committed.

III. PRESENT STATUS - SO_2 EMISSIONS

The present status of SO_2 emissions as related to the operation of the NB Power system is characterized by:

- Use of heavy fuel oils with sulphur contents up to 2.75% on an annual average basis for the:
  - 1000 MW Coleson Cove Plant
  - 265 MW Courtenay Bay Plant
  - 100 MW Dalhousie #1 Unit

- Use of a total of 500,000 tonnes annually of high sulphur (6-8% average) indigenous New Brunswick coal at the:
  - 85 MW Grand Lake Plant
  - 200 MW Dalhousie #2 Unit

- Hydraulic generation providing some 25% of in-province energy requirements (15% of total energy supplies).

- Displacement of energy generation from thermal plants by purchased energy from Hydro-Quebec when available.

- Energy exports to Prince Edward Island and the U.S. New England region whenever availability, economic opportunity, contractual arrangements, and transmission allovs.

- Fuel switching, or reductions in generation, whenever predictive computerized supplementary control systems or monitored observations determine it is required to meet local airshed requirements.

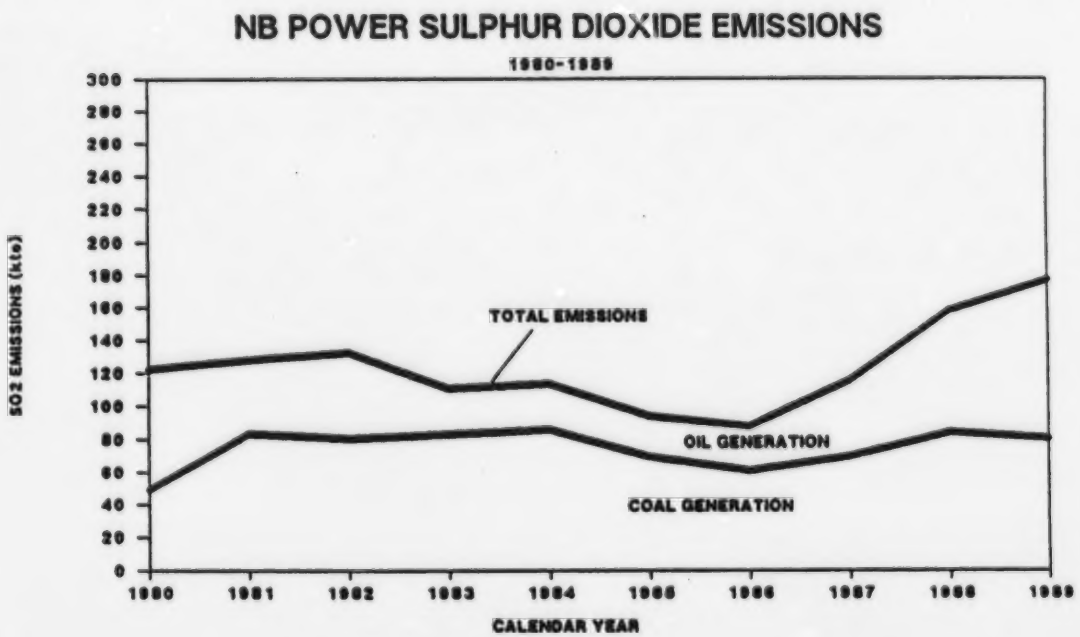
The SO_2 emissions which have existed, in the period 1980 to 1989, from the NB Power system are provided by plant in Table I and plotted by fuel type in Figure I.

TABLE 1

NB POWER PLANT SO_2 EMISSION DATA 1980-1989
(tonnes x 1000)

PLANT	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
Coal Fired										
Grand Lake	32.9	38.1	35.1	31.0	33.7	25.9	16.9	24.4	27.6	28.2
Dalhousie #2	16.4	45.1	45.7	52.1	52.3	43.3	44.1	44.6	56.3	52.0
Chatham #2	--	--	--	--	--	--	--	.6	0.4	0.4
Sub-Total Coal	49.3	83.2	80.8	83.1	86.0	69.2	61.0	69.6	84.3	80.6
Oil-Fired										
Coleson Cove	54.5	36.3	44.1	23.5	24.6	21.2	22.7	38.6	58.4	74.0
Dalhousie #1	3.5	--	--	--	--	--	--	1.3	4.8	8.3
Chatham #1	--	--	--	--	--	--	--	.1	0.2	--
Courtenay Bay	15.0	8.6	7.7	4.5	3.1	3.6	4.1	5.6	10.2	14.0
Sub-Total Oil	73.0	44.9	51.8	28.0	27.7	24.8	26.8	45.6	73.6	96.3
TOTAL	122.3	128.1	132.6	111.1	113.7	94.0	87.8	115.2	157.9	176.9

FIGURE I



IV. DEVELOPING CONDITIONS - SO_2 EMISSIONS

The level of emissions generated by the NB Pover thermal plants is, of course, directly related to the required utilization of these plants in meeting load requirements. The major influences, in the period 1980 to 1989, have been the addition of the 630 MW nuclear unit at Point Lepreau and the high availability of surplus energy available from Hydro-Quebec. The latter is a rapidly reducing impact as surpluses from Hydro-Quebec are being erased by load grovth and by its heavy export commitment to the U.S. market. The trend nov is to a rapid increase in emissions as thermal plant use rises with increased loads and reduced energy availability from Hydro Quebec.

In 1988 NB Pover signed a contract with Hydro Quebec providing for the supply of quantities of firm energy and capacity for the years up to, and including 1994. This contract was expected to reduce the increase in SO_2 emissions during these years. In 1989 this reduction did not occur. Continued near drought conditions in Quebec resulted in very lov reservoirs and belov normal hydro generation which caused Hydro Quebec to purchase large blocks of thermally generated energy from Nev Brunswick. This situation is projected to continue at least through 1990 until Hydro Quebec reservoirs are recharged. But in the longer term, with normal weather conditions in Quebec, the contract should enable Nev Brunswick to reduce SO_2 emissions. In addition the contract allovs NB Pover to meet projected load grovth requirements while nev generation is being constructed.

Presently committed generation additions are a 100 MW oil fuelled peaking unit scheduled for the Miramichi area in 1991, the 450 MW Belledune thermal plant scheduled to be in service in 1993, to be fuelled with imported coal and a 150/200 MW thermal plant to be in service in 1994, located at Grand Lake, near Minto, and fuelled with locally mined high sulphur (6% - 8%) coal. Both the Belledune and Grand Lake coal fired thermal plants are to be equipped with sulphur removal capabilities.

Total N.B. Coal production will be limited to some 500,000 tonnes per year. Following the in-service of the new Grand Lake unit all New Brunswick mined coal will then be consumed at the Grand Lake Plant. The Dalhousie 200 MW #2 unit, which prior to this would have used New Brunswick coal will be supplied with lower sulphur fuel.

Projections for in-province requirements beyond 1994 indicate a need for a further increment of generation to be in service no later than 1997 or 1998. This generation could be either another 450 MW coal fired thermal unit with sulphur removal capability or, if determined to be more feasible, a 450 MW nuclear unit depending on economics of the alternatives and when they are required to be in service.

This new generation development combined with the existing system quantities, will allow NB Power to meet its forecast in-province requirements and hoped for export energy opportunities over existing interconnections throughout the 90's. But, operation of the system as presently planned without a deliberate sulphur dioxide emissions control program, would result in annual NB Power sulphur dioxide emission levels of some 200,000 tonnes by the year 2000.

V. SO_2 CONTROL PROGRAM

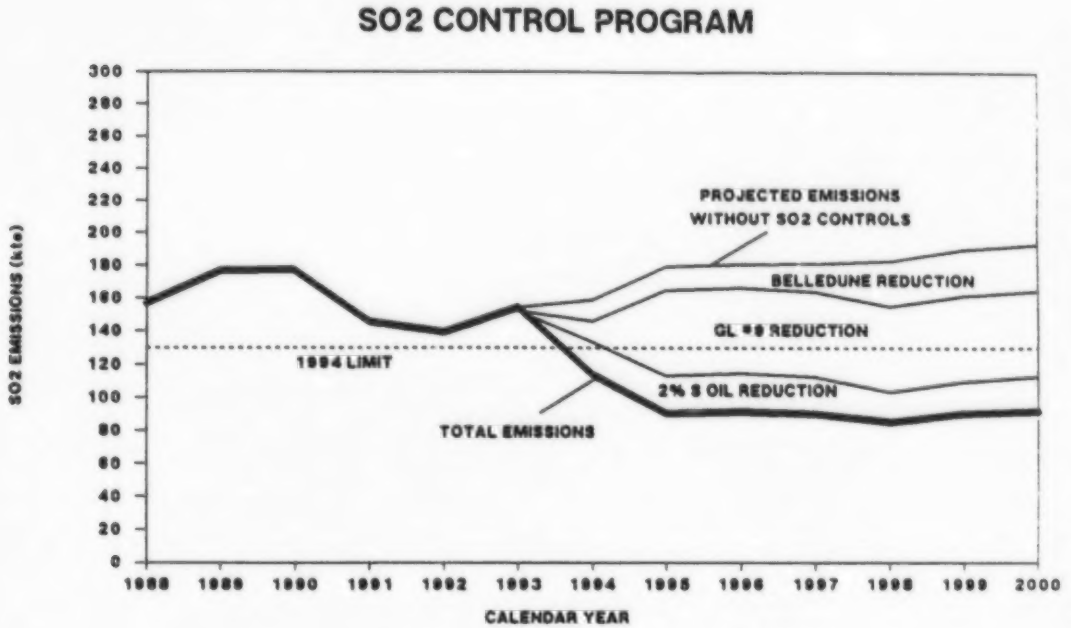
The SO_2 emission reduction program being undertaken by NB Power to meet the 1994 annual limit of 130,000 tonnes integrated with NB Power's long term development plan consists of the following:

- Installation of a 450 MW coal fired unit at Belledune in 1993 with SO_2 control capability to a level of 0.6 lb/10^6 BTU of fuel consumed.
- Utilization of lower sulphur oil in existing oil fired units.
- Installation of a 150/200 MW coal fired unit at Grand Lake in 1994 with 90% SO_2 removal capability.
- Dalhousie #2 unit fueling changed from indigenous New Brunswick coal to lower sulphur fuel in 1994.
- An additional 450 MW generation source will be added not later than 1997 or 1998. This unit, if thermal, will be equipped with SO_2 control capability to a level of 0.6 lb/10^6 BTU of fuel consumed.
- New Brunswick coal utilization maintained at no more than 500,000 tonnes/year.
- Annual export sales of 4000 GWh in 1994 increasing to 5000 GWh by 2000.

The projected SO_2 emissions resulting from this program with 2% sulphur oil are illustrated in Figure II. Individual plant emissions and projected capacity factors for the years 1994 and 2000 are set out in Table II. The reductions attributable to flue gas desulphurization at Belledune are those compared to the operation of the project as originally proposed for environmental review. The SO_2 emissions are shown to be well below the

130,000 tonne level from 1994 to the year 2000. Sufficient margin exists such that the 130,000 tonne limit would not be exceeded even if there are demands on NB Power thermal generation for high levels of interconnection support similar to that provided Quebec in 1989.

FIGURE II



A major component of this plan involves use of lover sulphur oil. Flexibility is intended such that Courtenay Bay plant could be at 1.0% S. oil and other plants operated on higher sulphur levels for an equivalent system average of 2.0% S. At this time no attempt was made to optimize levels that would exist for different plants although it is more reasonable that Courtenay Bay, being located near the Saint John City core, would use lover sulphur oil than other plants.

TABLE II

PROJECTED PLANT SO_2 EMISSIONS

PLANT	YEAR 1994 Estimated % CF	YEAR 1994 Kte SO_2	YEAR 2000 Estimated % CF	YEAR 2000 Kte SO_2	Notes
Coal Fired:					
Grand Lake #8	79%	26	40%	13	3
Grand Lake #9	15%	1	70%	6	1,2,3
Dalhousie #2	46%	33	79%	10	4
Chatham #2	0%	0	1%	0	3
Belledune #1	74%	7	83%	8	5
Belledune #2			81%	8	5
Sub-Total Coal		67		45	
Oil Fired:					
Coleson Cove	45%	38	43%	38	6
Dalhousie #1	27%	3	28%	3	6
Courtenay Bay	25%	5	25%	5	6
Sub-Total Oil		46		46	
TOTAL		113		91	

Notes:

1. Sulphur removal capability predicted to remove up to 90% of total SO_2
2. Grand Lake #9 projected to be in service November 1, 1994 with SO_2 removal capability
3. Grand Lake units and Chatham #2 burning 6-8% S. coal
4. Dalhousie #2 burning 6-8% S. coal to October 31, 1994 then switching to sulphur fuel (1% S. coal or equivalent)
5. Belledune 450 MW units with SO_2 control capability to 0.6 $lb/10^6$ BTU of fuel consumed
6. Coleson Cove, Dalhousie #1 and Courtenay Bay burning 2% average S. oil

VI. ALTERNATIVE SO_2 CONTROL PROGRAMS

Several alternative methods of reducing SO_2 emissions are available to NB Power. Some of these could be implemented in place of using lower sulphur oil. Development considerations such as delays in the in-service of Grand Lake #9 unit or a decision to proceed with Lepreau #2 also impact SO_2 emissions. The following alternative programs are presented to provide an overview of options that could be employed. Clearly, other programs could be constructed by combining these options in different ways.

A. COLESON COVE ORIMULSION ALTERNATIVE

This alternative replaces low sulphur oil with the conversion of #2 unit at Coleson Cove to burn orimulsion coupled with the installation of flue gas desulphurization equipment on that unit. Implementation is contingent upon satisfactory contractual arrangements with a fuel supplier and both the economic and technical feasibility of the new fuel relative to low sulphur oil. Results for this program are given in Figure III and Table III.

FIGURE III

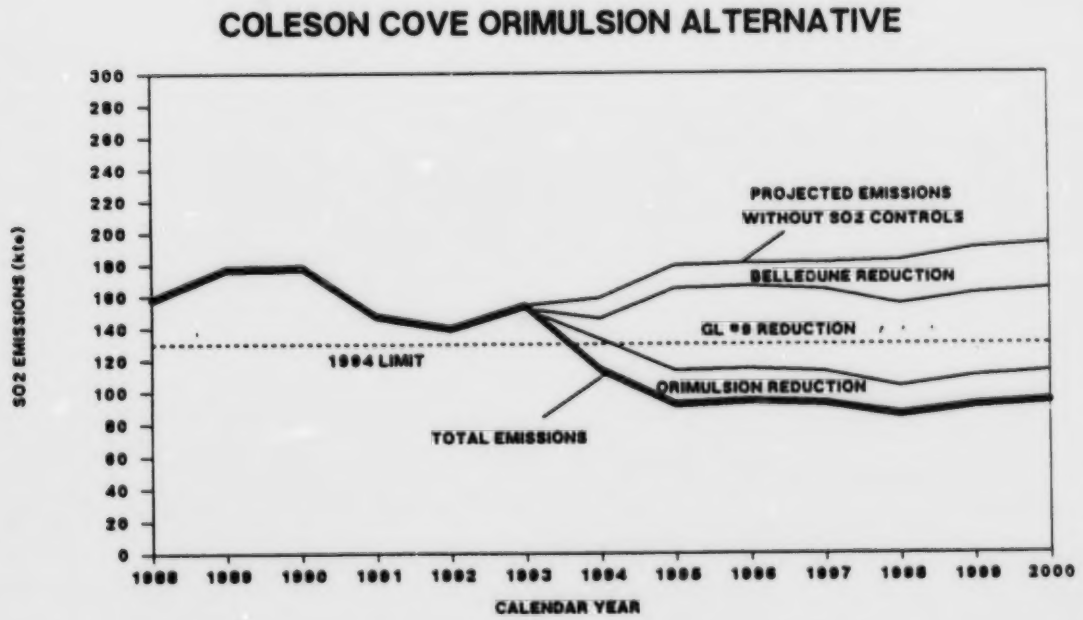


TABLE III

PLANT SO_2 EMISSIONS - COLESON COVE ORIMULSION ALTERNATIVE

PLANT	YEAR 1994 Estimated % CF	YEAR 1994 Kte SO_2	YEAR 2000 Estimated % CF	YEAR 2000 Kte SO_2	Notes
Coal Fired:					
Grand Lake #8	78%	25	40%	13	3
Grand Lake #9	15%	1	70%	6	1,2,3
Dalhousie #2	44%	33	78%	10	4
Chatham #2	1%	0	1%	0	3
Belledune #1	69%	7	83%	8	5
Belledune #2			81%	8	5
Sub-Total Coal		66		45	
Oil Fired:					
Coleson Cove #1&3	41%	31	42%	32	6
Coleson Cove #2	70%	4	79%	4	1,7
Dalhousie #1	32%	4	30%	4	6
Courtenay Bay	27%	8	26%	8	6
Sub-Total Oil		47		48	
TOTAL		113		93	

Notes:

1. Sulphur removal capability predicted to remove up to 90% of total SO_2
2. Grand Lake #9 unit projected to be in service November 1, 1994 with SO_2 removal capability
3. Grand Lake units and Chatham #2 burning 6-8% S. coal
4. Dalhousie #2 burning 6-8% S. coal to October 31,1994 then switching to low sulphur fuel (1% S. coal or equivalent)
5. Belledune 450 MW units with SO_2 control capability to 0.6 $lb/10^6$ BTU of fuel consumed
6. Coleson Cove #1 & 3, Dalhousie #1 and Courtenay Bay burning 2.75% S. oil
7. Coleson Cove #2 burning 2.9% S. Orimulsion™ with SO_2 removal capability

B. REDUCED EXPORT SALES ALTERNATIVE

This alternative reduces all economy export sales, which are expected to be supplied from oil fired units, to 50% of the levels otherwise projected. This is a reduction of some 1400 GWh of sales, 140 GWh of which would have gone to Prince Edward Island and the remainder to the New England states. With the exception of reduced levels of export sales and use of lov sulphur oil, all other elements of this alternative are the same as the proposed SO_2 control program outlined in Section IV. This alternative would only, of course, be under taken if the economics of lover sulphur content fuel were unacceptable.

Figure IV illustrates the projected annual levels of SO_2 emissions for this alternative and Table IV sets out individual plant emissions and projected capacity factors for the years 1994 and 2000.

FIGURE IV

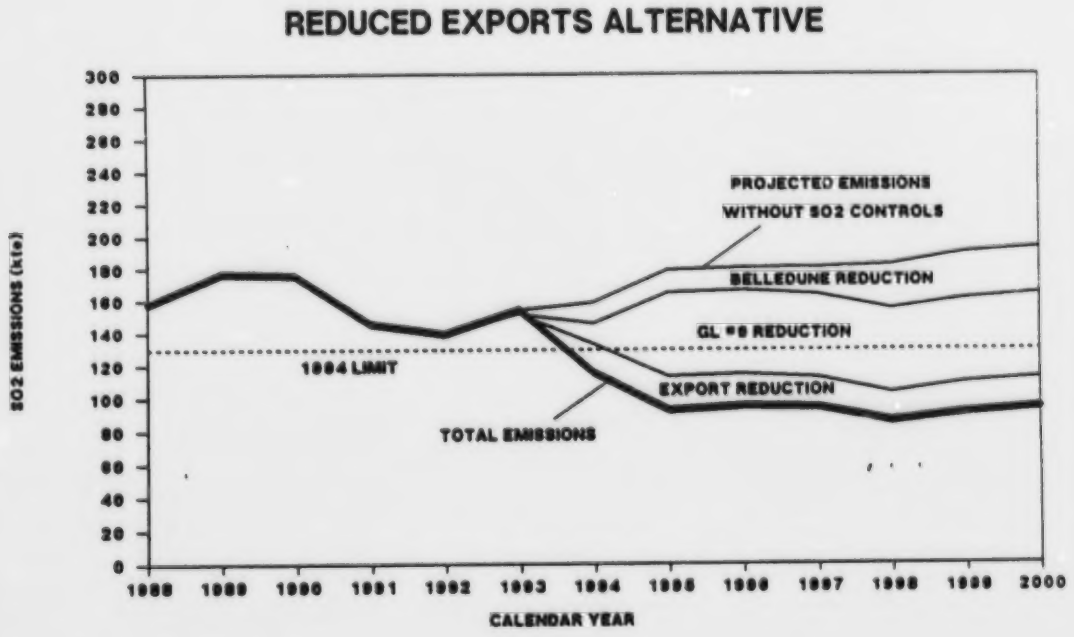


TABLE IV

PLANT SO_2 EMISSIONS - REDUCED EXPORTS ALTERNATIVE

PLANT	YEAR 1994 Estimated % CF	YEAR 1994 Kte SO_2	YEAR 2000 Estimated % CF	YEAR 2000 Kte SO_2	Notes
Coal Fired:					
Grand Lake #8	78%	25	40%	13	3
Grand Lake #9	15%	1	70%	6	1,2,3
Dalhousie #2	46%	33	79%	10	4
Chatham #2	0%	0	1%	0	3
Belledune #1	74%	7	83%	8	5
Belledune #2			81%	8	5
Sub-Total Coal		66		45	
Oil Fired:					
Coleson Cove	35%	41	35%	41	6
Dalhousie #1	16%	2	15%	2	6
Courtenay Bay	17%	5	17%	5	6
Sub-Total Oil		48		48	7
TOTAL		114		93	

Notes:

1. Sulphur removal capability predicted to remove up to 90% of total SO_2
2. Grand Lake #9 projected to be in service November 1, 1994 with SO_2 removal capability
3. Grand Lake units and Chatham #2 burning 6-8% S. coal
4. Dalhousie #2 burning 6-8% S. coal to October 31, 1994 then switching to lov sulphur fuel (1% S. coal or equivalent)
5. Belledune 450 MW units with SO_2 control capability to 0.6 $lb/10^6$ BTU of fuel consumed
6. Coleson Cove, Dalhousie #1 and Courtenay Bay burning 2.75% S. oil
7. Export reductions are predicted to be 140 GWh to Prince Edvard Island and 1260 GWh to Nev England; all from oil fired units

C. PURCHASE ALTERNATIVE (IF AVAILABLE)

Another alternative to the use of lover sulphur oil would be to purchase firm energy from out-of-province sources if any is available. The results of this alternative, specifically the purchase of 3 TWh annually from 1988 to 2000 are shown in Figure V and Table V.

FIGURE V

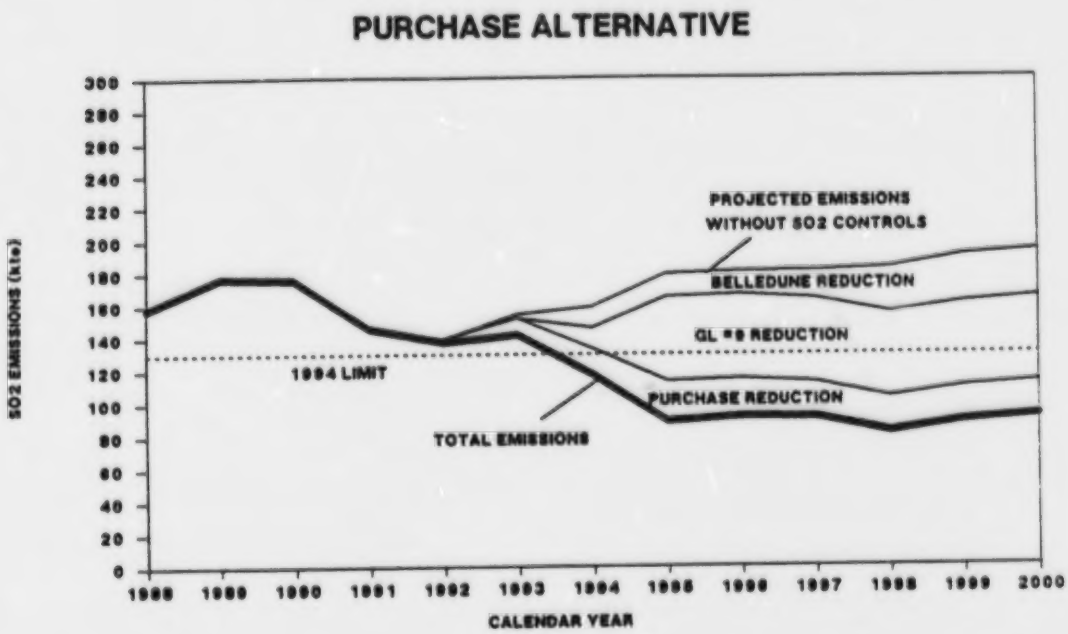


TABLE V

PLANT SO_2 EMISSIONS - PURCHASE ALTERNATIVE (IF AVAILABLE)

	YEAR 1994		YEAR 2000		
PLANT	Estimated % CF	Kte SO_2	Estimated % CF	Kte SO_2	Notes
Coal Fired:					
Grand Lake #8	72%	23	40%	13	3
Grand Lake #9	14%	1	70%	6	1,2,3
Dalhousie #2	41%	30	78%	10	4
Chatham #2	0%	0	0%	0	3
Belledune #1	69%	7	83%	8	5
Belledune #2			80%	8	5
Sub-Total Coal		61		45	
Oil Fired:					
Coleson Cove	40%	47	35%	40	6
Dalhousie #1	19%	2	8%	1	6
Courtenay Bay	20%	6	16%	5	6
Sub-Total Oil		55		46	
TOTAL		116		91	

Notes:

1. Sulphur removal capability predicted to remove up to 90% of total SO_2
2. Grand Lake #9 projected to be in service November 1, 1994 with SO_2 removal capability
3. Grand Lake units and Chatham #2 burning 6-8% S. coal
4. Dalhousie #2 burning 6-8% S. coal to October 31, 1994 then switching to low sulphur fuel (1% sulphur coal or equivalent)
5. Belledune 450 MW units with SO_2 control capability to 0.6 $lb/10^6$ BTU of fuel consumed
6. Coleson Cove, Dalhousie #1 and Courtenay Bay burning 2.75% S. oil

D. BLEND NB COAL AT BELLEDUNE ALTERNATIVE

The construction of the Grand Lake #9 unit with sulphur removal capability, coupled with conversion of the Dalhousie #2 unit from high sulphur New Brunswick mines coal to a lower sulphur fuel, form a major part of NB Power's SO_2 emission central program. Should a 1994 in-service date for the Grand Lake #9 project not be achievable there would be a need for additional SO_2 reduction until the unit were available.

Reduction of SO_2 could be accomplished by reducing economy sales or by increasing purchases as shown previously in alternatives B and C. Another method would be to begin burning low sulphur fuel in the Dalhousie #2 unit and blending the New Brunswick mined coal with low sulphur coal in the Belledune unit when it is available with its 90% sulphur removal equipment. Projections for this option are given in Figure VI and Table VI under the assumption that the Grand Lake #9 unit is delayed one year to November 1995.

FIGURE VI

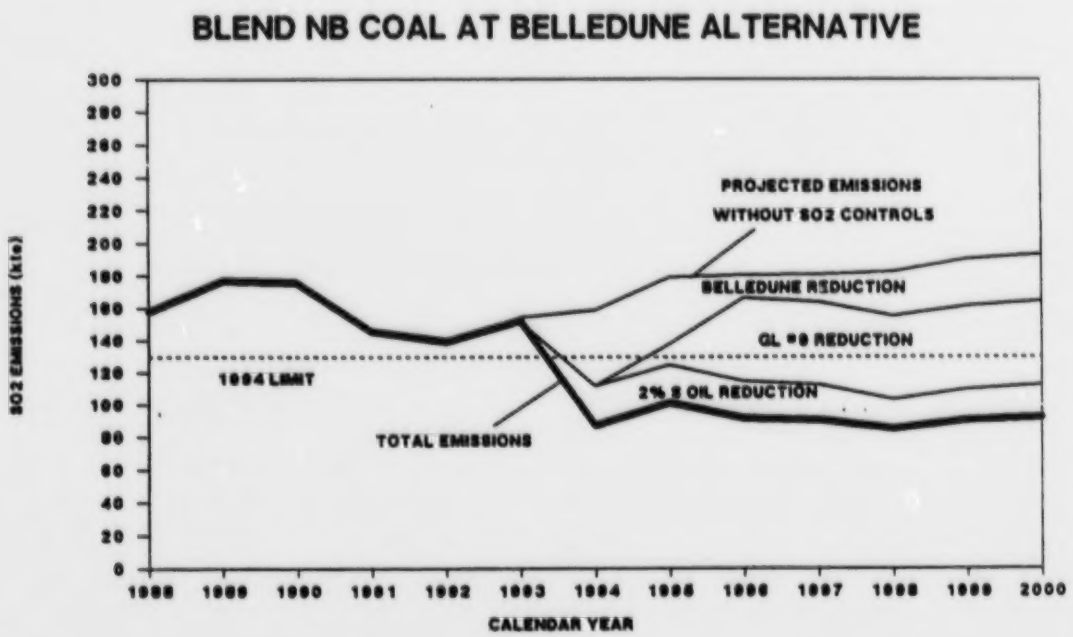


TABLE VI

PLANT SO_2 EMISSIONS - BLEND NB COAL AT BELLEDUNE ALTERNATIVE

PLANT	YEAR 1994 Estimated % CF	YEAR 1994 Kte SO_2	YEAR 2000 Estimated % CF	YEAR 2000 Kte SO_2	Notes
Coal Fired:					
Grand Lake #8	79%	26	40%	13	3
Grand Lake #9			70%	6	1,2,3
Dalhousie #2	64%	8	79%	10	4
Chatham #2	0%	0	0%	0	3
Belledune #1	76%	7	83%	8	5,6
Belledune #2			81%	8	5
Sub-Total Coal		41		45	
Oil Fired:					
Coleson Cove	46%	40	43%	38	7
Dalhousie #1	27%	3	28%	3	7
Courtenay Bay	25%	5	25%	5	7
Sub-Total Oil		48		46	
TOTAL		89		91	

Notes:

1. Sulphur removal equipment predicted to remove up to 90% of total SO_2
2. Grand Lake #9 with SO_2 removal capability in service delayed until November 1, 1995
3. Grand Lake units and Chatham #2 burning 6-8% S. coal
4. Dalhousie #2 switched to lov sulphur fuel (1% S. coal or equivalent) beginning January 1, 1994
5. Belledune 450 MW units with SO_2 control capability to 0.6 $lb/10^6$ BTU of fuel consumed
6. Belledune blends 26,000 tonnes per month of high sulphur Nev Brunsvick mined coal with lover sulphur coal until the Grand Lake #9 unit is available.
7. Coleson Cove, Dalhousie #1 and Courtenay Bay burning 2.0% S. oil

E. NUCLEAR ALTERNATIVE

Replacement of the second 450 MW Belledune coal unit, should it not be undertaken by 1997 or 1998, with a 450 MW nuclear unit located at the Point Lepreau Generating Station is a development path which would contribute to lover SO_2 emissions.

The nuclear alternative, along with the use of lover sulphur fuel oil would, of course, provide long term SO_2 reductions. The projected SO_2 emissions resulting with nuclear development integrated into the SO_2 reduction program are illustrated in Figure VII. Individual plant emissions and projected capacity factors are presented in Table VII.

FIGURE VII

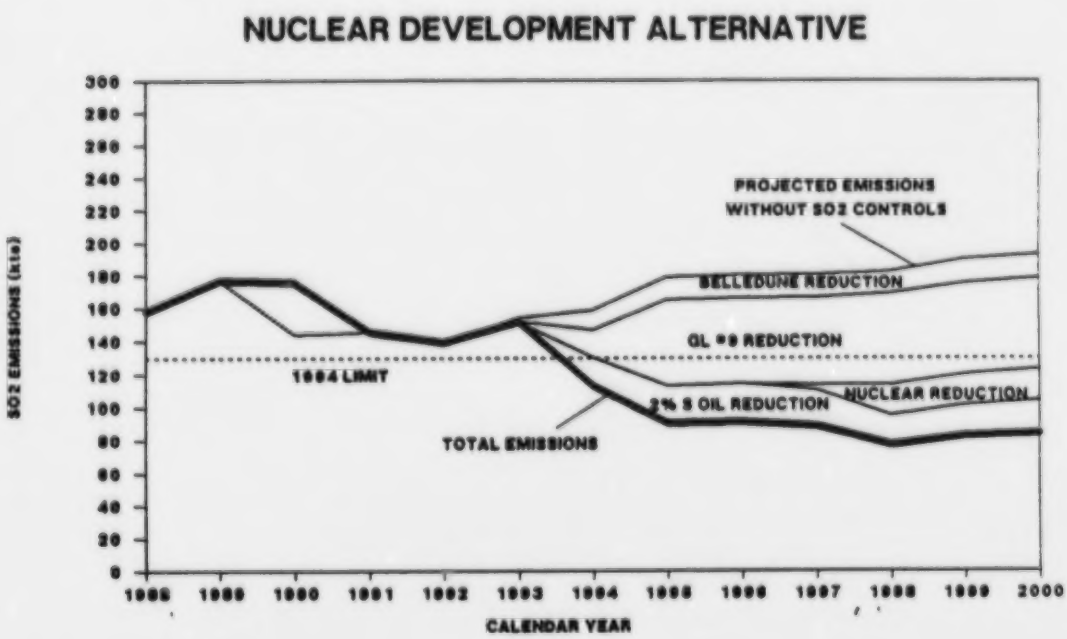


TABLE VII

PLANT SO_2 EMISSIONS - NUCLEAR DEVELOPMENT ALTERNATIVE

PLANT	YEAR 1994 Estimated % CF	YEAR 1994 Kte SO_2	YEAR 2000 Estimated % CF	YEAR 2000 Kte SO_2	Notes
Coal Fired:					
Grand Lake #8	79%	26	40%	13	3
Grand Lake #9	15%	1	70%	6	1,2,3
Dalhousie #2	46%	33	78%	10	4
Chatham #2	0%	0	1%	0	3
Belledune #1	74%	7	83%	8	5
Lepreau #2	-	-	81%	0	
Sub-Total Coal		67		37	
Oil Fired:					
Coleson Cove	45%	38	43%	38	6
Dalhousie #1	27%	3	28%	3	6
Courtenay Bay	25%	5	25%	5	6
Sub-Total Oil		46		46	
TOTAL		113		83	

Notes:

1. Sulphur removal capability predicted to remove up to 90% of total SO_2
2. Grand Lake #9 unit projected to be in service November 1, 1994 with SO_2 removal capability
3. Grand Lake units and Chatham #2 burning 6-8% S. coal
4. Dalhousie #2 burning 6-8% S. coal to October 31,1994 then switching to low sulphur fuel (1% S. coal or equivalent)
5. Belledune 450 MW unit with SO_2 control capability to 0.6 lb/10^6 BTU of fuel consumed
6. Coleson Cove, Dalhousie #1 and Courtenay Bay burning 2.0% S. oil